June 26, 2000
Dockets Facility
U.S. Department of Transportation
Room PL-401
400 Seventh Street, SW
Washington, DC 20590-0001

RE: [Docket No. RSPA-99-6355; Notice 3] Pipeline **Integrity Management in High Consequence Areas**

The Interstate Natural Gas Association of America (INGAA) appreciates the opportunity to submit comments on the above referenced notice of proposed rulemaking. I appreciate your considering these late filed comments.

INGAA represents the majority all of the major interstate natural gas transmission companies operating in the United States and interprovincial pipelines operating in Canada as well as natural gas companies in Mexico and Europe. INGAA's United States members, which account for over 80 percent of all natural gas transported and sold in interstate commerce, are regulated by the Office of Pipeline Safety (OPS), Department of Transportation. INGAA's members safely transport over 25% of the nation's energy needs.

INGAA and its member companies are not directly impacted by the above referenced rule. The rule applies to operators of hazardous liquid pipelines that are regulated by the Department of Transportation under 49 CFR Part 195. INGAA is submitting comments because we are concerned about the manner in which the Research and Special Program Administration (RSPA) has interpreted provisions under 49 U.S.C. 60102 of the Accountable Pipeline Safety and Partnership Act of 1996. We also desire to distinguish natural gas transmission pipelines from hazardous liquid pipelines. The repeated references in the preamble to "pipeline industry" are a concern because natural gas pipelines and the liquid pipelines are in separate and distinct industries. Finally, we urge RSPA to conduct a full cost-benefit analysis on this proposed rule and any future rule that addresses pipeline integrity issues.

INGAA is also concerned that RSPA has ignored the requirements and the benefits of the present pipeline safety regulations in this notice. Both the hazardous liquid pipeline regulations and the natural gas pipeline safety regulations were modeled after industry standards based on integrity practices. In the case of natural gas pipeline standards, ANSI B31.8 was designed as an integrity plan that took into account varying consequences such as population density. This industry standard and the subsequent regulations modeled after this standard have resulted in outstanding integrity in both rural and urban areas. Regulatory requirements that already take into account high density population areas should be assessed as part of the future rulemaking process.

COMMENTS ON THE PREAMBLE

INGAA has the following comments on the statutory requirements section of this noitice.

STATUTORY REQUIREMENTS

INGAA is concerned that the RSPA implies by this statement that the criteria for identifying gas pipeline facilities located in high-density population areas has not been defined.

> *49 U.S.C. 60109(a)(2)--OPS is* ***to prescribe standards establishing criteria for identifying gas*** *pipeline* ***facilities located in high-density population areas*** *and hazardous liquid pipelines that cross waters where a substantial likelihood of commercial navigation exists, located in a high-density population area, or in an area unusually sensitive to environmental damage (USAs).*

The specific statutory requirement is listed below.

(a) Identification Requirements.--Not later than October 24, 1994,
the Secretary of Transportation shall prescribe standards that--
(1) establish criteria for identifying--
(A) by operators of gas pipeline facilities, each gas pipeline facility (except a natural gas distribution line) located in a high-density population area; and
(B) by operators of hazardous liquid pipeline facilities and gathering lines--

OPS has had standards for high density criteria for natural gas transmission facilities since the adoption of 49 CFR 192 in 1970. This definition, listed below, clearly defines a high population density area around the natural gas transmission pipeline.

Sec. 192.5 Class locations.

(a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.

(1) A ``class location unit'' is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.

(2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

(1) A Class 1 location is:

(i) An offshore area; or

(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

(2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

(3) A Class 3 location is:

(i) Any class location unit that has 46 or more buildings intended for human occupancy; or

(ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:

(1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

INGAA also believes the preamble in the proposed rule inappropriately interprets the provisions of 49 U.S.C. 60102(f)(2).

49 U.S.C. 60102(f)(2)--OPS ***is to prescribe additional standards requiring the periodic inspection of pipelines*** *in USAs and high-density population areas. The regulations are to prescribe when an instrumented internal inspection device, or similarly effective inspection method, should be used to inspect the pipeline.*

The actual statute listed below acknowledges that it may not be necessary to have additional standards for some pipelines and that there are situations where instrumented internal inspection devices are not required. The statute is listed below.

2) Periodic inspections.--Not later than October 24, 1995, the Secretary shall prescribe, **if necessary**, additional standards requiring the periodic inspection of each pipeline the operator of the pipeline identifies under section 60109 of this title. The standards shall include any circumstances under which an inspection shall be conducted with an instrumented internal inspection device and, if the device is not required, use of an inspection method that is at least as effective as using the device in providing for the safety of the pipeline**.**

Concurrently, the reference in the notice does not recognize that the actual Statute identifies that the Secretary has the option to extend the requirements to accommodate smart pigs whose basic construction would accommodate an instrumented internal inspection device but is not required. In any case, there is no statutory requirement to extend the requirements whose basic structure does not accommodate an instrumented internal inspection device.

(f) Standards as Accommodating ``Smart Pigs''.--

(1) Minimum safety standards.--The Secretary shall prescribe minimum safety standards requiring that--

(A) the design and construction of new natural gas transmission pipeline or hazardous liquid pipeline facilities, and

(B) when the replacement of existing natural gas transmission pipeline or hazardous liquid pipeline facilities or equipment is required, the replacement of such existing facilities be carried out, to the extent practicable, in a manner so as to accommodate the passage through such natural gas transmission pipeline or hazardous liquid pipeline facilities of instrumented internal inspection devices (commonly referred to as ``smart pigs''). The Secretary **may extend** such standards to require existing natural gas transmission pipeline or hazardous liquid pipeline facilities, whose **basic construction would accommodate** an instrumented internal inspection device to be modified to permit the inspection of such facilities with instrumented internal inspection devices.

Clearly, Congress intended discretion in the design of any regulation requiring internal inspection devices.

INGAA has the following comments on the following titled sections of the preamble.

RISK MANAGEMENT INITIATIVES

INGAA questions the accuracy of this statement;

OPS further found that liquid operators generally have more experience than natural gas operators with using internal inspection devices.

INGAA member companies have used internal inspection tools on over 40,000 miles and have an extensive cooperative research and development program to improve inline inspection. Many of improvements in technology of inline inspection have roots in these research programs. Internal inspection technologies vary because of the median in which the inspection is being performed and the type of defect to be analyzed. Internal inspection of pipelines with a compressible fluid is much more demanding, requiring more understanding of the capabilities of the internal inspection devices. Natural gas operators have extensive knowledge with internal inspection devices.

PUBLIC MEETING

INGAA concurs with some of the participants.

*Some participants maintained that defining **actual impact zones would be preferable** to the classic population corridor used in the gas regulations.*

We agree that actual impact zones be examined. The original corridor concept for natural gas pipelines was originally developed by the industry after examining impacts of natural gas incidents and it was incorporated into ANSI B31.8. Natural gas is primarily composed of methane and is lighter than air. The affected area of a natural gas incident is limited to the immediate area around the pipeline. The characteristics of various hazardous liquids and consequences are different and should be not treated the same.

HIGH CONSEQUENCE AREAS

INGAA concurs that population density based on U.S. Census data is an acceptable alternative for defining high population density when there is not a more refined methodology such as the definition of class location now present in the natural gas pipeline safety regulations.

*High population areas are areas of the United States with moderate to high population densities. The U.S. Census Bureau calls these places ``Urbanized Areas'', and defines them as areas that contain 50,000 or more people and have a **population density of at least 1,000 people per square mile.***

In the case of natural gas pipelines, the class location definition more accurately describes the population density in the affected area around the pipeline. Natural gas pipelines have already identified these high density population areas and constantly update these designations by visual surveillance resulting in a more accurate categorization than the aforementioned census layers. Record keeping systems have been developed over the years to manage this system since the requirement (1970) was enacted. There is not a need to utilize the National Mapping System to continue this record keeping effort on the natural gas transmission pipelines.

INTEGRITY ASSESSMENT TOOLS

Corrosion / Metal Loss

INGAA concurs that the Magnetic Flux Leakage (MFL) tool is applicable to both natural gas and hazardous liquid pipelines when it can be accommodated. Care must be taken to analyze the results of these devices and judgment needs to be applied to the accuracy of these devices including the ability to generate false positives and negative indications. Also, the application of this technology must take into account non-metallic reinforcement techniques (i.e. clockspring) that may give inaccurate results as to the integrity of the pipeline.

THE PROPOSED RULE

INGAA concurs with RSPA that hazardous liquids and natural gas have different physical properties, pose different risks and the configuration of the systems differ.

> *OPS has decided to implement integrity management requirements for hazardous liquid and natural gas transmission operators in several steps. Natural gas and liquids* ***have different physical properties****,* ***pose different risks, and the configuration of the systems differ****.*

What must be in the Baseline Assessment Plan?

INGAA is confused by the statement that an internal inspection tool must be capable of detecting deformation anomalies, including gouges and grooves.

> *An internal inspection tool would have to be capable of detecting corrosion and deformation anomalies including dents,* ***gouges and grooves***

The previous statements about the capabilities of MFL and geometry tools did not indicate that these tools were capable of detecting these defects. Extensive research has been performed to gauge the ability of MFL tools to detect and characterize gouges, grooves and the attending "coldworking" of the remaining material caused by mechanical damage. Additional research and improvements will be needed before this technology is commercially available. Mechanical damage can occur during the construction of a pipeline and consequently will be subject to the initial hydrostatic pressure test already required in the pipeline safety regulations. This type of material and construction defect is not predicted to grow in the fatigue regime that a natural gas pipeline exists operates.

Mechanical damage that is the result of outside force (i.e. excavation) is a random event. Almost all of these critical defects fail immediately upon damage, making inline inspection a very inefficient tool for discovering these defects. Additional information on this subject is included in GRI Report **GRI-99/0050 Effectiveness of Various Means of Preventing Pipeline Failures From Mechanical Damage .**

When Must the Baseline Assessment Be Completed?

There appears to no technical basis for non-acceptance of an integrity acceptance method that is greater than 5 years.

> *The proposed rule allows an operator to use an integrity assessment method* ***conducted five years*** *before the effective date of the final rule as the baseline assessment if the method is at least equivalent to the requirements for internal inspection, pressure testing or alternative technology*.

The establishment of a baseline should be based on the type of technology used and the subsequent preventative measures used to control time-dependent defects. Static defects that are detected and removed in a baseline test should not have restriction on baseline assessment timeframe. Available inspection information indicating successful mitigation of time dependent flaws should be taken into consideration. Additional wall thickness due to varying design criteria should also be considered in this assessment.

Availability of inspection equipment and restrictions of deliveries to customers due to testing, inspection and remediation should also be incorporated into the assessment. The establishment of strict overly conservative schedules will result in significant interruptions to customers or require extensive overbuilding of redundant facilities.

What Remedial Action Must be Taken?

INGAA believes there are many factors that must be taken into account in scheduling of remedial action. In the case of natural gas, interruption of customers can cause extensive safety risks to residential, commercial and industrial customers.

> *For all other conditions, the rule proposes that an operator base the schedule for evaluation and repair on the risk factors used for establishing an assessment schedule and* ***on specified criteria*** *if the operator uses an internal inspection tool.*

Ignoring this key piece of information can result in overall higher safety risk to the public resulting in unintended consequences.

What Is a Continual Evaluation of a Pipeline's Integrity?

INGAA believes that there is no technical basis for establishing the integrity assessment period of the first option.

In option one, the rule proposes that an operator establish intervals not to exceed ten (10) years for assessing the pipeline's integrity.

In the case of natural gas transmission pipelines, the present pipeline safety regulations already require measures to mitigate time-dependent defects (i.e. corrosion). The past performance of these pipeline time-dependent mitigation management systems indicates that this timeframe (10 years) is conservative. The addition of additional wall thickness on natural gas pipelines in areas of high density areas further adds to this conservative estimate.

Appendix C

It is unclear how Appendix C. fits into the context of this rulemaking and the time interval in Option 1.

Regulatory Analysis and Notices

Executive Order 12866 and DOT Regulatory Policies and Procedures

The proposed rule does not consider this action to be a significant action under section 3(f) of Executive Order 12866 but this action is required to have cost / benefit performed as described in 49 U.S.C. 60102 (b)(2) as shown below.

> (2) Factors for consideration.--When prescribing any standard under this section or section 60101(b), 60103, 60108, 60109, 60110, or 60113, the Secretary shall consider--
> (A) relevant available--
> (i) gas pipeline safety information;
> (ii) hazardous liquid pipeline safety information; and
> (iii) environmental information;
> (B) the appropriateness of the standard for the particular type of pipeline transportation or facility;
> (C) the reasonableness of the standard;
> (D) based on a **risk assessment**, the reasonably identifiable or **estimated benefits** expected to result from implementation or compliance with the standard;
> (E) based on a risk assessment, the reasonably identifiable or **estimated costs** expected to result from implementation or compliance with the standard;
> (F) comments and information received from the public; and
> (G) the comments and recommendations of the Technical Pipeline Safety Standards Committee, the Technical Hazardous Liquid Pipeline Safety Standards Committee, or both, as appropriate.

INGAA participated in the development of the procedure to conduct a cost benefit analysis. We note, that the Office of Pipeline Safety Framework for a Cost Benefit

Analysis was not used in the development of this proposed rule. OPS did an excellent job in developing the Cost Benefit Framework which documents how agencies and regulated entities should work together too analyze the true problem, documents the existing industry baseline, evaluates regulatory alternatives, and attempts to quantify the costs and benefits. We urge OPS to use this analysis technique in exploring the feasibility and benefit of this notice and any new standards on this subject.

Many items of the analysis is missing. A "target problem" of what is to be solved by this rulemaking is not included. An analysis of the types of defects considered, their frequency, and the consequences on public safety and environment are not documented in this notice. The effectiveness of the proposed solution is not discussed in this notice. No listing of and subsequent discussions of possible alternatives to the proposed rule are listed in this notice. Benefits of the proposed integrity program are not quantified and the assumptions for the costs incurred by industry are not sufficiently detailed and appear inaccurate. Finally, no assessment was made as to the cost effectiveness of this notice.

COMMENTS ON THE RULE LANGUAGE

INGAA submits the following comments on the specific rule language

§ 195.452 (b)(2)

The language term "best industry practices" is not defined and is very ambiguous

> *…an operator must follow* ***best industry practices*** *(BIP) unless the section specifies otherwise or the operator demonstrates that the deviation is backed by a reliable engineering evaluation….*

INGAA is unaware of any source of this information. This should probably refer to appropriate industry consensus standards not practices.

§ 195.452 (c) (1)

The language assumes that MFL or caliber based inline technology will find gouges and grooves and correctly assess defects that are harmful to the integrity of the pipe.

> *…internal inspection tool capable of detecting corrosion and deformation anomalies including dents,* ***gouges and grooves****….*

See previous comments on the feasibility of these tools to detect delayed mechanical damage.

§ 195.452 (c) (1)

The language in the footnote limits the assessment of the baseline integrity of a certain pipelines to hydrostatic pressure testing.

> [2] *A magnetic flux leakage or ultrasonic internal inspection survey shall not be used for a segment constructed of low frequency electric resistance-welded pipe (ERW pipe) and lapwelded pipe susceptible to longitudinal seam failures.*

The critical defects related to this type of pipe are static in nature for natural gas transmission pipelines and are removed during an initial hydrostatic pressure test. Extensive research has shown that remaining defects after a successful hydrostatic pressure test do not grow in pipes in natural gas transmission service due to the fatigue cycle regime. Therefore, if a pipeline has been tested at least once time in its lifetime these critical defects will be removed and the use of MFL inspection should not be excluded as a alternative for a baseline test.

§ 195.452 (d) (2)

The language describes an arbitrary cutoff date with no technical justification

> *…An operator may use an integrity assessment method conducted after [insert date* ***five years*** *before the effective date of the final rule] as the baseline assessment if the method meets the requirements of this section…..*

Refer to previous comments concerning the preamble.

§ 195.452 (g)

The language does not take into account the public safety of the customers of the product being delivered in the analysis.

> *…For all other conditions, an operator must base the schedule for evaluation and repair on the risk factors listed in paragraph (e)(1) of this section…*

In some cases, the risk to the public of a shutdown of a pipeline facility for inspection, testing or remediation can be higher because of reliance on a product or shutdown and startup sequences of the customer.

§ 195.452 (j) (1)

The language assumes that MFL or caliber inline technology will find gouges and grooves that are harmful to the integrity of the pipe.

> *…internal inspection tool capable of detecting corrosion and deformation anomalies including dents,* ***gouges and grooves****…*

See previous comments on the feasibility of these tools to detect delayed mechanical damage.

Appendix C to Part 195 – Prioritizing Risk Factors

See previous comments on preamble.

Conclusion

In conclusion, it is our hope that when RSPA analyses potential pipeline integrity standards for the natural gas transmission industry they; utilize the statutorily required cost / benefit procedures; document the regulatory baseline that is used for rural areas; quantify the effect of present pipeline integrity regulations in more densely populated areas and decide what, if any, additional standards are needed.

If you have any questions please contact me at tboss@ingaa.org or call (202)216-5930.

Sincerely Yours

Terry Boss
Vice President, Environment Safety and Operations